PREDICTION OF TEMPERATURE PROFILE OF INJECTED CHEMICAL ALONG THE TUBULAR

by

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DISSERTATION

Submitted to Petroleum Engineering Programme in Partial Fulfillment of the Requirements for the Degree Bachelor of Engineering (Hons)

(Petroleum Engineering)

May 2011

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CERTIFICATION OF APPROVAL

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Approved

....

(Mr Elias Abllah)

Project Supervisor

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

May 2011

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements and that the original work contained herein have not been undertaken or done by unspecified sources or persons

(KUEH JING ZHI)

ABSTRACT

During petroleum production, organic solid deposition will accumulate in the wellbore and along the tubing. Therefore, production will be reduced due to blockage of production path by organic solid deposition. To solve blockage of production path, high temperature chemical will be injected into wellbore to treat organic solid deposition. As surrounding temperature is lower, heat will be transferred from wellbore to surrounding. Hence, prediction of temperature profile of injected chemical is needed so that suitable amount and reliable thermophysical properties of chemical can be predicted. The objective of this project is to examine temperature drop of injected chemical.

Microsoft Excel® 2007 together with Microsoft Visual Basic for Application (VBA) is used to predict temperature profile of injected chemical. Model developed by Hasan and Kabir will be utilized in this computer program. This project is divided into 2 parts. First part of project will predict heat transfer and temperature profile of injected chemical. Second part of project will examine sensitivity parameters of injected chemical.

In this project, there are several assumptions made to simplify the program created. Simulation of temperature profile of injected chemical is shown in graph. Sensitivity parameters are identified so that sensitivity analysis can be conducted. Sensitivity parameters identified are injection rate, injection temperature and fluid density. The result of computer program implies that it is plausible to predict temperature profile of injected chemical based on computer program created. Computer program can be used on other type of injection fluid like water. Optimal chemical condition for organic solid deposition treatment will be high injection rate, high fluid density and suitable injection temperature.

ACKNOWLEDGEMENT

First and foremost, it would be fit to extend my highest gratitude to my Final Year Project Supervisor, Mr Elias bin Abllah. It is a privilege to be under his supervision. Even with his tight schedules, there is no moment where he fails to provide support and guidance. His advice and moral supports gave a sense of strength and confidence in conducting my Final Year Project.

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Nomenclature:

A = inverse relaxation distance parameter, ft
c_p = heat capacity, Btu/(lbm-°F)
C_J = Joule-Thomson coefficient, °F/psi
g_c = conversion factor, 32.17 (lbm-ft)/(lbf-sec^2)
g_T = geothermal gradient, °F/ft
h_c = convective heat-transfer coefficient, Btu/(°F-hr-ft)
H = fluid enthalpy, Btu/lbm
k_c = conductivity of casing material, Btu/(hr-ft-°F)
k_{cem} = conductivity of cement, Btu/(hr-ft-°F)
k_e = conductivity of earth or formation, Btu/(hr-ft-°F)
L = total measured well depth, ft
L_R = relaxation distance parameter, 1/ft
t_D = dimensionless time = $ket/\rho_e c_e r_{wb}^2$
T_{ei}, T_e = formation temperature at initial condition at any radial distance, °F
T_{eibh} = static formation temperature at the bottomhole or wellhead, °F
T_f = fluid temperature, °F
T_{wb} = temperature at wellbore/formation interface, °F
T_D = dimensionless temperature = $(2\pi k_e)(T_{wb}-T_{ei})/Q$
U = overall heat transfer coefficient, Btu/(hr-ft^2-°F)
z = variable well depth from surface, ft
α = wellbore inclination with horizontal, degree

Subscripts:

c = casing
ci = casing inside
co = casing outside
cem = cement
ins = insulation
t = tubing
ti = tubing inside
to = tubing outside
wb =wellbore

CHAPTER 1

INTRODUCTION

1.1 Background of Study

1.1.1 Organic Solid Deposition

Solid deposition is a very common problem in production well. It is happening almost in every production well all over the world. Although solid deposition differs from one to another (area, field and well), it has universal effects on production of well.

After a well is drilled and completed, the well will start its production and crude oil will be produced from the well. When a well is producing, operators will face many flow assurance problems, which include solid deposition. Solid deposition can be

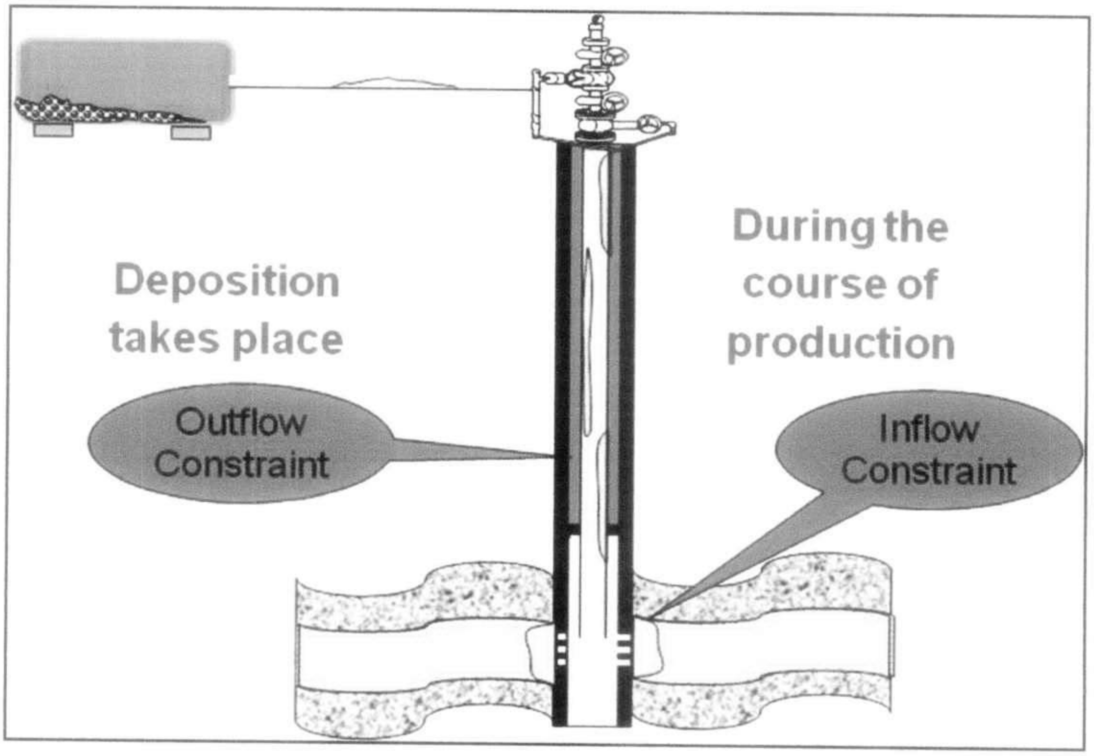


Figure 1: Organic solid deposition occurrence in the well.

broadly divided into two types, which are, organic (asphaltene and paraffin) and inorganic (calcium carbonate, barium sulphate, sand).

During production, crude oil produced from the well will experience drops in temperature and pressure. When there is temperature and pressure drops during production, organic solid deposit will start to crystallize and accumulate in the wellbore and along the tubing. If organic solid deposit starts to accumulate and deposit in the wellbore and along the tubing, production will be less due to blockage of production path by organic solid deposit. It will block production flow ultimately if it is not treated. As shown in Figure 1, organic solid deposition will cause inflow constraint and outflow constraint to production.

There are several components inside organic solid deposit, which are, asphaltene, paraffin, aromatics and resin. Out of four components inside organic solid deposit, only asphaltene and paraffin create serious problems to flow assurance of well. Asphaltene and paraffin will block the production path when the well is under production. While the roles of aromatics and resin is to stabilize asphaltene and paraffin. Aromatics will stabilize paraffin and resin will stabilize asphaltene.

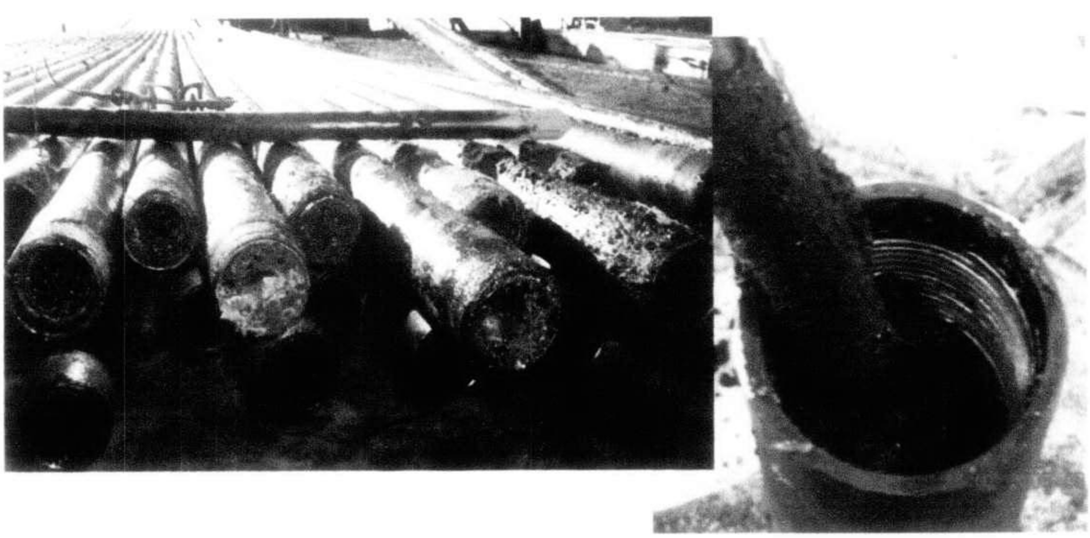


Figure 2: Asphaltene accumulation and paraffin crystallization inside tubing.

1.1.2 Asphaltene

Asphaltene is C70+ macromolecular substance that can be found in crude oil. Asphaltene has no specific chemical structure. Broadly speaking, asphaltene is fractions of oil that are insoluble in n-heptane or n-pentane and soluble in benzene/toluene. Asphaltene is dark brown to black solid with no defined melting point. It decomposed under heating and leave carbon residue. Asphaltene is normally polar due to presence of nitrogen, oxygen, sulfur and various metals in its molecular structure.

Appearance of asphaltene is related to the stability of asphaltene. Stability of asphaltene depends on properties of asphaltene fraction and how good the crude oil can dissolve asphaltene. If there is plenty of good asphaltene solvents inside crude oil, asphaltene will not appear in the tubular. Asphaltene deposition does not relate to the concentration in crude oil. Some crude oil with high asphaltene content may not form deposit while some low asphaltene content crude oil may have serious asphaltene deposition problem.

Asphaltene can cause problems in oil production, transportation and processing. In oil production, asphaltene will decrease oilfield productivity by plugging formation and creating skin in and around wellbore. It will dramatically reduce rock permeability, thus causing formation damage. Huge amount of cost is generated due to prevention and removal of asphaltene deposit.

1.1.3 Paraffin

Paraffin, which is also known as alkane, is a type of hydrocarbon with general formula of C_nH_{2n+2}. Paraffin refers to a mixture of alkane which has the range within C18 and C70. Usually paraffin is straight chain hydrocarbon, but in some cases it is branched hydrocarbon. Paraffin is normally found as white, odorless, tasteless waxy solid with typical melting point between 47°C and 64°C. Paraffin is inert to any chemical reactions; therefore it is resistant to attack by acids and bases.

As paraffin is temperature related, appearance of paraffin depends on the temperature in the wellbore and along the tubing. If the temperature of the crude oil drops below wax appearance temperature (WAT) or cloud point, paraffin will crystallize and deposit in the tubular. Range of WAT is typically between 30°C and 40°C, and cloud point of the each type of paraffin differs from one another.

Deposition of paraffin can take place in the wellbore, tubing and surface equipment due to sharp decline in temperature and pressure. When paraffin is accumulated in and around the wellbore, it can cause decrease in permeability and production of crude oil. Removal of paraffin deposit is prone to thermal treatment as it is strongly temperature-dependent.

1.1.4 Combating Organic Solid Deposition

There are several ways to combat organic solid deposition in wellbore and tubing. Organic solid deposition treatment can be divided into mechanical means, hot fluid, solvents, dispersants, and crystal modifier and inhibitor.

Removal by mechanical means is the oldest method known to remove organic solid deposit. It is done by mechanically scraping the tubing and flowline by using pigs. This method is a very troublesome operation as disposal of the deposit is another problem to operators. Besides, this method is not effective in removal of organic solid deposition in formation.

Removal by hot fluid fully utilizes high temperature of hot oil, hot water and steam. This is done by circulating hot fluid to remove organic solid deposit from wellbore and injecting into formation to open up plugged area. By injecting and circulating hot fluid in wellbore and formation, organic solid deposit is melted and flow out from formation and wellbore.

Uses of solvents as organic solid deposition treatment can be divided into carbon disulfide, chlorinated solvents, benzene, xylene and toluene. When solvents in injected into wellbore and formation, it will come into contact with organic solid deposit. Solvent will dissolve organic solid deposit until solvent reaches its saturation level.

Dispersants in organic solid deposition treatment are most popular chemical used in treatment. Dispersants disperse paraffin in oil and water through surfactant action. It is usually added into injected solution before solution is injected.

Crystal modifier and inhibitor is a class of chemical which prevents agglomeration of paraffin crystals. It attacks nucleating agent of hydrocarbon and hinders agglomeration of paraffin. In order for crystal modifier or inhibitor to be effective it has to constantly present in crude oil. So, it is normally injected continuously into well or squeeze further into formation to prolong its effects.

1.1.5 Thermo-chemical System

In order to treat organic solid deposition, a unique thermo-chemical system two pack system will be developed. Two pack system consists of two formulations incorporating a blend of solvents and other active components. It is an effective tool for removing the organic solid deposition near-and-around wellbore and production tubing, thus enhancing the production from treated well. (Remy Azrai et al., 2007)

Normally, in thermal method, heat is utilized to melt solid deposits. While in chemical method, dispersion and surfactant properties of the chemical are utilized to dissolve and disperse solid deposits within the crude. In thermo-chemical system, both chemical and thermal properties are utilized in addressing organic solid deposition problems. (Ibrahim and Ali, 2005)

Normally chemical used in thermo-chemical system consists of organic acidic solution and alkaline solution. First, chemical used will be tested so that chemical which is compatible to organic solid deposit can be selected. It is selected based on the nature of oil and organic solid deposits.

Chemical used is produced by mixing organic acid solution and alkaline solution together. When organic acidic solution and alkaline solution are mixed together, the reaction products are ester, solvents and heat. Before it can be employed in the field, chemical had to go through another testing. Chemical is tested by soaking it at the desired condition for certain period. The objective of soaking is to ensure that chemical used will not solidify the crude oil selected.

Once chemical used passes these two tests, it can be employed in the field. The reaction products will be used to treat organic solid deposits. Reaction products can be used to treat both asphaltene and paraffin. Ester and solvents inside chemical will be used to treat asphaltene. As asphaltene is composition related, ester and solvents will treat asphaltene by changing the composition of asphaltene. Thus asphaltene will dissolve inside crude oil. Heat produced will be used to treat paraffin as paraffin is temperature dependent. Paraffin will dissolve when the temperature of paraffin rise above its cloud point.

The treatment of organic solid deposition starts at the wellhead. Organic acidic solution and alkaline solution will be mixed in advance at wellhead. When organic acidic solution and alkaline solution are mixed together, the temperature of the mixture will rise to between 120°C and 160°C. After these 2 solutions are mixed together, it will be injected into the wellbore.

When chemical is injected into the wellbore, chemical will travel for some distance before it reach its intended stop point. While chemical is travelling inside the tubular, the temperature difference between chemical inside tubular and the formation will cause heat transfer from fluid to its surroundings or vice versa. Heat transfer will depend on temperature difference of fluid and surroundings. Heat will transfer from high temperature medium to low temperature medium. As temperature of chemical is higher, heat will travel from chemical inside tubular to its surroundings. As heat is constantly transferred from tubular to the surroundings, temperature will drop continuously as chemical travels until chemical injected reaches its stop point.

In this project, heat loss of injected chemical into surroundings to treat organic solid deposition will be predicted and investigated. Once the heat loss of injected chemical into surroundings is known, variables that will affect heat transfer of fluid and formation will be studied in detail.

1.2 Problem Statement

Problem Identification

High temperature chemical is used to treat organic solid deposition in the wellbore and along the tubing. When chemical is injected into the tubular, heat contained inside injected chemical will dissipate to its surroundings as it travels inside the tubular. Once injected chemical reaches its end point, it might not have enough heat to treat the well as heat is dissipated to surroundings. Thus, its main objective, that is, to use its heat to dissolve components of organic solid deposition, cannot be achieved. Thus, predictions of heat loss and temperature drop of injected chemical inside tubular are needed.

After heat loss and temperature drop of injected chemical inside the tubular are known, temperature of injected chemical when it reaches its end point can be predicted. Heat loss of injected chemical can be predicted and calculated by knowing chemical and well properties. Once the heat loss of injected chemical at the end point is known, the prediction of chemical temperature at bottomhole can be made. Once temperature of chemical injected is predicted, sensitivity analysis will be conducted to examine effects of sensitivity parameters to heat transfer and temperature profile of injected chemical.

Significance of the project

Heat transfer model and temperature drop of injected chemical are important parameter in this project. By knowing heat transfer model and temperature drop of injected chemical when it is injected into the tubular, suitable injection rate, injection temperature and amount of chemical needed to treat organic solid deposition can be investigated and predicted.

It is essential to know the properties including amount of chemical needed to have a successful organic solid deposition treatment. If amount of chemical injected is less than amount required, heat contained inside chemical injected is not sufficient. Thus, organic solid deposition treatment is not successful and further treatment is needed. This will add more cost to company as additional investment is needed for additional treatment. If injected chemical into tubular is more than needed, excess fluid injected will become wastage as excess injected chemical does not increase the production of the well. It might tally up total cost to a company.

1.3 Objectives

The objectives of the project are:

a) To investigate heat loss and temperature drop of injected chemical into the tubular.

b) To investigate various parameters that will affect injected chemical temperature at bottomhole.

c) To evaluate the computer program created.

1.4 Scope of Study

The scope of study is mainly about heat loss and temperature drop of injected chemical when chemical is injected into the tubular and amount of chemical needed to achieve certain temperature when it reaches its stop point. The project is divided into 2 parts.

First part of the project is the investigation of heat loss and temperature drop of injected chemical into the tubular. Heat loss of injected chemical to the surroundings can be used to measure temperature drop. By knowing heat loss of injected chemical, temperature drop can be predicted based on the computer program created.

Second part is about investigation and examination of sensitivity parameters that will affect temperature of injected chemical at bottomhole. Once sensitivity analysis of these parameters are identified and examined in details, prediction of amount of injected chemical needed to achieve certain temperature can be predicted. It is predicted based on heat transfer model of injected chemical along the tubular. The prediction is done based on the computer program created too.

1.5 Relevancy of the project

This project can be used for the prediction of amount of chemical needed for treatment of organic solid deposition inside the tubular and the well. Suitable amount of chemical should be decided so that chemical used can treat organic solid deposition successfully. If amount of chemical used is less than required, it will not provide enough heat to treat organic solid deposition. If there is excess amount of chemical used to treat the well, it will increase total cost of the company.

1.6 Feasibility of the Project within the Scope and Time Frame

With the proper planning beforehand, the project will be kept inside the scope of the project and the project can finish within the time frame. For example, Gantt chart created will assist in planning of the activities done during the whole course of project.

Besides, under the supervision and guidance of my supervisor, Mr Elias Abllah, I am confident that the project will be achieved within the scope and time frame set beforehand.

CHAPTER 2

LITERATURE REVIEW

2.1 Literature Review

When fluid flows inside the wellbore, there will be transfer of heat between fluid inside tubular and the surroundings. It is because there is difference between fluid and geothermal difference. Transfer of heat between the fluid inside the tubular and the earth is happening in all drilling and production operations. (Ramey, 1962)

Wellbore fluid temperature is mainly controlled by rate of heat loss from the wellbore to the surrounding formation. Rate of heat loss is influenced by depth of the formation and production/injection time. (A.R. Hasan and C.S. Kabir, 1994)

Many have investigated methods to estimate downhole temperature as early as 1930-s. In 1937, Schlumberger et al realized the usefulness of wellbore fluid temperature measurement. In the early 1950, Nowak (1953) and Bird (1954) proposed the water and gas profile by interpret the temperature log. It is one of the earliest applications of heat transfer principle.

By utilizing previous work by various authors, Kirkpatrick (1959) prepared flowing temperature gradient chart. But this chart is lack of generality and accuracy. It is due to lack of complete understanding of physics of heat flow. Thermal stress failure of casing in steam-injection wells emphasized the importance of proper understanding of wellbore heat transfer and accurate estimation of flowing fluid temperature.

There are continuous researches conducted by several authors independently. Procedures for estimating wellbore fluid temperature were suggested by several parties including Lesem et al (1957), Moss and White (1959). However, Ramey (1962) and Edwardson et al (1962) were the first to present a theoretical model for estimating fluid temperature as a function of well depth and producing time. But the theoretical model has limited application due to negligence of the effect of kinetic energy and friction and applicable only for single phase fluid flow.

Theoretical model prepared by Ramey and Edwardson et al was improved by Satter (1965). Satter's work incorporated the effect of phase change for steam injection wells. Shiu and Beggs (1980) further improve the work by suggesting a method of estimating a specific parameter in Ramey's equation.

Ramey's approach of relating fluid and formation temperature is taken as references by many to estimate wellbore heat loss. There are continuous research done to improve the accuracy and applicability of the theoretical model.

Griston and Willwhite (1987) extend the application of Ramey's method by evaluating the usefulness of concentric steam injection wells. Besides, they point out the importance of radiative heat transfer in steam injection.

Temperature profile of water injection well was also studied by Smith and Steffensen (1970). They identified various factors which affect shut-in absolute temperature profile, which includes friction heating in injection zones, convective heat transfer, wellbore configuration, thermal conductivities of formation and wellbore materials, injection temperature, and injection time. In 1975, Smith and Steffensen further their studies of effects of injection rate and surface temperature on injection temperature profile.

Witterholt and Tixier (1972) and Curtis and Witterholt (1973) used the influence of fluid flow rate on fluid temperature in Ramey's equation, in conjuction with measured fluid temperature, for qualitative estimation of flow rate from various producing zones. But the method has limited use especially for estimating flow rates from multiple zones because the method depends on the establishment of a constant temperature difference between wellbore fluid and surroundings.

These applications of Ramey's model are restricted to single-phase flow in the wellbore only, with a radius that is small. Sagar et al. (1991) extended Ramey's method for wellbore with multiphase flow. The work by Sagar et al. accounts for kinetic energy effects and Joule-Thompson expansion.

Almehaideb et al. (1989) studied the effects of multiphase flow and wellbore phase segregation during well testing. They used a fully implicit scheme to couple the wellbore and an isothermal black-oil reservoir model. The wellbore model accounts only for mass and momentum changes with time.

In 1980, Miller developed one of the earliest transient wellbore simulators, which account for changes in geothermal-fluid energy while flowing up the wellbore. In this model, mass and momentum equation are combined with energy equation to yield an expression for pressure. After solving for pressure, density, energy and velocity are calculated for the new timestep at a well gridblock.

A wellbore simulator for analyzing gas-well buildup test was developed by Fan el al. (2000). The model uses a finite-difference scheme for heat transfer in the vertical direction. The heat loss from the fluid to the surroundings in radial direction is represented by an analytical model.

A study by Izgec et al. (2007) improved the wellbore simulator developed by Fan et al. in this formulation of wellbore simulator, finite-difference forms of mass and momentum equations are coupled with a semianalytic heat-transfer model, which can represent heat transfer in both the vertical and radial directions. The solution of the finite-difference equations can be handled by one of three matrix solvers, which is specified by the users. Matrix operations are not required for energy calculations because of semianalytic formulation. This efficient coupling with the semianalytic heat transfer model greatly increased the computational speed.

A prediction model that can generate flow rate, pressure and temperature profiles along the wellbore based on reservoir and surface condition was developed by Yoshioka et al. in 2005. This prediction model can be applied to complex well which includes horizontal, multi-branching and multilateral well. It examines effects of Joule-Thomson effects and well trajectories on temperature and pressure profile. This paper concludes that temperature and pressure changes in horizontal well sensitive to small changes in surrounding condition. Gas is more affected by Joule-Thomson effect as it is compressible.

In 2009, Muradov and Davies explored various theoretical models and software tools to model the temperature distribution in wells with advanced completion. In this paper, an analysis of the scientific basis and the technical utility of available modeling tools like steady state, well flow simulator and dynamic well flow simulator are discussed. In addition, several methods to directly calculate the inflow distribution into the well using different suites of measurement for complex, advanced completion were discussed.

In 2010, Semenova et al had created a model to calculate the temperature and pressure of reservoir while it is in production. The model has been implemented in Stanford's General Purpose Research Simulator (GPRS). This model calculates both pressure and temperature profiles along the well for standard wells and wells with complicated trajectories.

CHAPTER 3

THEORY

3.1 Formation Temperature Distribution

To model heat flow and temperature distribution in the wellbore and surroundings, fluid inside the formation is treated as homogenous fluid. By assuming symmetry around the well, the three-dimensional (3D) problem can be simplified into two-dimension (2D) problem. In addition, heat diffusion in the vertical direction may be ignored due to small vertical temperature gradients. By neglecting vertical heat flow, the system can be reduced to a one-dimensional (1D) heat diffusion problem. This approach introduces very little error and allows analytical solution to the problem. This analytical approach is preferred to numerical solution because numerical solution is tedious and time consuming.

Boundary conditions can be obtained from the examination of the physical system. The initial formation temperature is assumed to be time invariant. At very early times ($t = 0$), formation temperature everywhere is equal to initial formation temperature. Besides, at the outer boundary, the formation temperature is assumed does not change with radial distance. So the slope is zero. The resultant two boundary conditions are:

$$\lim T_e \rightarrow T_{ei} \text{ as } t \rightarrow 0 \tag{1}$$

$$\lim \partial T_e/\partial r \rightarrow 0 \text{ as } r \rightarrow \infty \tag{2}$$

Fourier law for heat transfer at the formation and wellbore interface is also used. The resulting solution requires Bessel function of zero and first order over the limits of zero to infinity. By using the algebraic approximations developed by Hasan and Kabir (1994), it is adequate for most engineering purposes.

$$T_D = \left(0.4063 + \frac{1}{2}\ln t_D\right)\left(1 + \frac{0.6}{t_D}\right) \text{ if } t_D > 1.5 \quad (3)$$

$$T_D = 1.1281\sqrt{t_D}\left(1 - 0.3\sqrt{t_D}\right) \text{ if } t_D \leq 1.5 \quad (4)$$

3.2 Energy Balance for Wellbore Fluid

In the wellbore, temperature difference between wellbore fluid and surrounding formation causes energy exchanges. Ramey made an energy balance for the fluid by assuming fluid flow is single-phase flow. A general energy balance for either a single-phase flow or two-phase flow is as below.

$$\frac{dT_f}{dz} = \frac{1}{c_p}\frac{dH}{dz} + C_J\frac{dp}{dz} \quad (5)$$

$$\frac{dT_f}{dz} = \frac{1}{c_p}\left(\mp\frac{dQ}{dz} - \frac{g\sin\propto}{Jg_c} - \frac{v}{Jg_c}\frac{dv}{dz}\right) + C_J\frac{dp}{dz} \quad (6)$$

where negative sign applies to production and positive sign applies to injection.

3.3 Overall Heat Transfer Coefficient for Wellbore.

Radial heat transfer occurs between wellbore fluid and the earth, overcoming resistances offered by tubing wall, tubing insulation, tubing-casing annulus, casing wall, and cement. These resistances are in series.

When heat transfer occurs at steady rate, heat flowing through each of the elements will be the same. The expression for the overall heat transfer coefficient at steady rate heat transfer is:

$$\frac{1}{U_{to}} = \frac{r_{to}}{r_{ti} h_{to}} + \frac{r_{to} \ln(\frac{r_{to}}{r_{ti}})}{k_t} + \frac{r_{to} \ln(\frac{r_{ins}}{r_{to}})}{k_{ins}} + \frac{r_{to}}{r_{ins} (h_c + h_r)} + \frac{r_{to} \ln(\frac{r_{co}}{r_{ci}})}{k_c} + \frac{r_{to} \ln(\frac{r_{wb}}{r_{co}})}{k_{cem}} \quad (7)$$

In general, resistance to heat flow through casing and tubing can be neglected as conductivity of casing and tubing material is too large. Thus, the value of resistance is negligible. Besides, radiative heat transfer is ignored in fourth term as temperature difference between two medium are small. So, it does not make a lot of difference to overall heat transfer coefficient. First term of the equation on the right is ignored too as the value is negligible. So the simplified equation of overall heat transfer coefficient for wellbore is:

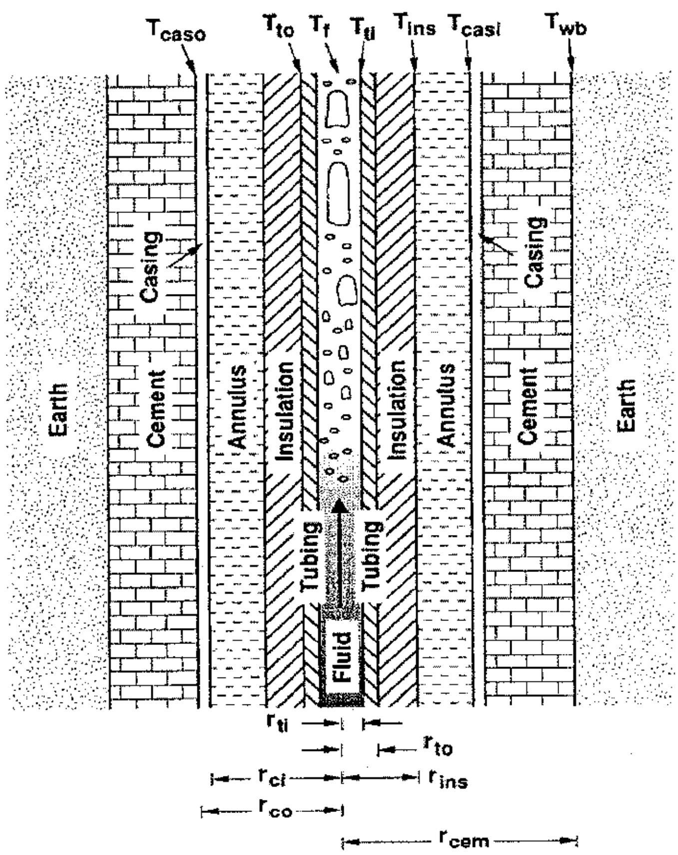


Figure 3: General well configuration involving a variety of elements.

$$\frac{1}{U_{to}} = \frac{r_{to} \ln(\frac{r_{ins}}{r_{to}})}{k_{ins}} + \frac{r_{to}}{r_{ins} (h_c)} + \frac{r_{to} \ln(\frac{r_{wb}}{r_{co}})}{k_{cem}} \quad (8)$$

3.4 Heat Transfer from Fluid into Formation

At steady state, the rate of heat flow, through a wellbore per unit length of the well, Q, can be expressed as:

$$Q = -2\pi r_{to} U_{to} (T_f - T_{wb}) \quad \text{(Heat transfer from fluid to wellbore)} \tag{9}$$

$$Q = \frac{-2\pi k_e}{T_D} U_{to} (T_{wb} - T_{ei}) \quad \text{(Heat transfer from wellbore to formation)} \tag{10}$$

Combining equation (9) and (10) and eliminating Twb, we can get heat loss from fluid to formation:

$$Q = -L_R w c_p (T_f - T_{ei}) \tag{11}$$

$$Q = -\frac{w c_p}{A} (T_f - T_{ei}) \tag{12}$$

L_R is the relaxation length parameter which is defined as:

$$L_R = \frac{2\pi}{c_p w} \left[\frac{r_{to} U_{to} k_e}{k_e + (r_{to} U_{to} T_D)} \right] \tag{13}$$

Parameter A, is inverse of parameter L_R, which is defined as:

$$A = \frac{c_p w}{2\pi} \left[\frac{k_e + (r_{to} U_{to} T_D)}{r_{to} U_{to} k_e} \right] \tag{14}$$

3.5 Fluid Temperature in Injection Wells

Now fluid temperature with variation to well depth can be obtained by substituting expression for heat loss to formation, (11), into energy balance equation (6).

$$\frac{dT_f}{dz} = \pm(T_f - T_{ei})L_R - \frac{g \sin\alpha}{c_p J g_c} - \frac{v}{c_p J g_c}\frac{dv}{dz} + C_J \frac{dp}{dz} \tag{15}$$

where the positive sign applies to production and the negative sign applies to injection.

The undisturbed formation temperature, T_{ei}, is assumed to vary with formation depth. So,

$$T_{ei} = T_{eibh} - g_T z \tag{16}$$

where g_T represents geothermal gradient in terms of vertical depth, and T_{eibh} is the static earth temperature at the bottomhole.

Equation (15) can be simplified as:

$$\frac{dT_f}{dz} = \pm(T_f - T_{ei})L_R - \frac{g \sin\alpha}{c_p J g_c} + \emptyset \tag{17}$$

where $\emptyset = C_J \frac{dp}{dz} - \frac{v}{c_p J g_c}\frac{dv}{dz}$ (18)

By using integrating factor method, equation (17) can be solved. The solution of equation (17) while flowing down a well is expressed as:

$$T_f = T_{ei} - \frac{1-e^{(z-L)L_R}}{L_R}\left[g_T \sin\alpha + \emptyset - \frac{g \sin\alpha}{c_p J g_c}\right] + e^{-zL_R}\left(T_{fwh} - T_{es}\right) \tag{19}$$

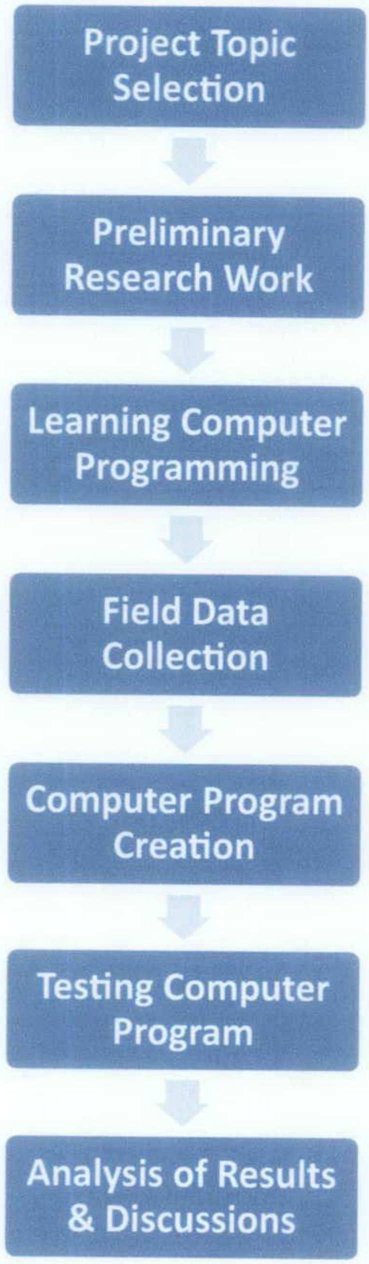
The value of parameter $\emptyset$ would depend on various variables, such as mass flow rate, wellhead pressure and gas liquid ratio. In this project, empirical expression for $\emptyset$ developed by Sagar et al is used.

$$\emptyset = -0.002978 + 1.006 \times 10^{-6} P_{wh} + 1.906 \times 10^{-4} W - 1.047 \times 10^{-6} GLR + 3.229 \times 10^{-5} API + 0.004009\gamma_g - 0.3551 g_T \tag{20}$$

CHAPTER 4

METHODOLOGY

4.1 Project Work Flow



1. Project Topic Selection

Project Topic will be selected either from a range of topics suggested by UTP lecturers or from students' proposal.

2. Preliminary Research Work

After the project topic is confirmed, preliminary research work will begin. It is done based on the project topic given. Preliminary research work can be done by reviewing the paper published in related journal and understanding of theory related to project topic in reference books.

3. Learning Computer Programming

As the heat transfer model will be created in computer program like Microsoft Excel® 2007 together with Microsoft Visual Basic for Application (VBA), the knowledge of computer programming is required. The understanding of computer programming will help in creation of heat loss model. Besides, it will assist in locating and correcting errors in the computer program created too.

4. Field Data Collection

Field data will be collected for the next step in this project. Field data like initial temperature of chemical, injection rate of chemical, diameter of tubular, amount of injected chemical, and depth of the well is gathered. All these data is crucial in creation of computer program as it can be used to test computer program created. The test can be done by comparing field data with the prediction from computer program.

5. Computer Program Creation

Computer program will be programmed to reproduce the heat transfer model of injected chemical when it is injected inside tubular. Computer program will be programmed based on theory and mathematical equations suggested by Hasan and Kabir. These mathematical equations will help to calculate heat transfer of injected chemical to surroundings. Then, temperature of injected chemical at certain depth in the well can be calculated.

6. Testing of Computer Program

After computer program is created, it will be used together with field data collected. Field data will be used inside computer program. These field data will be used to compare with results of computer program. The purpose of comparing field data with results of computer program is to test computer program created. By comparing field data together with computer program results, errors inside computer program can be eliminated and accuracy of computer program can be improved.

7. Results & Discussions

Results of the heat transfer model created in computer program will be discussed. The results obtained from computer program will be analyzed. The accuracy of the heat transfer model created will be discussed too. Various parameters that affect heat transfer of injected chemical will be examined and discussed in details. By identifying effects of parameters selected, heat transfer and temperature drop of injected chemical can be better predicted. If there is any error inside computer program, it will be discussed and solutions to the error inside computer program will be provided too.

4.2 Project Activities

There are few activities that are needed to be done throughout Final Year Project. These activities are:

a) Preliminary Research Work

b) Literature Review

c) Learning Computer Programming

d) Collection of field data

e) Creation of computer program

f) Testing of field data on computer program

4.3 Key Milestones

Milestones are selected in Final Year Project to track the progress of the project. Some of milestones selected are:

a) Creation of prediction of temperature profile.

b) Examination of effects of various parameters to heat transfer model of injected chemical.

4.4 Tools and Equipments

In this project, main tool required is computer. Simulation is done by using Microsoft Excel® 2007 together with Microsoft Visual Basic for Application (VBA).

4.5 Methodology

There are few steps that are needed to be done in order to predict the temperature profile:

1. Before prediction of temperature profile, details of injected chemical (initial temperature, injection rate, fluid density) and formation (total vertical depth, wellhead temperature, bottomhole temperature) are entered into Microsoft Excel® 2007.

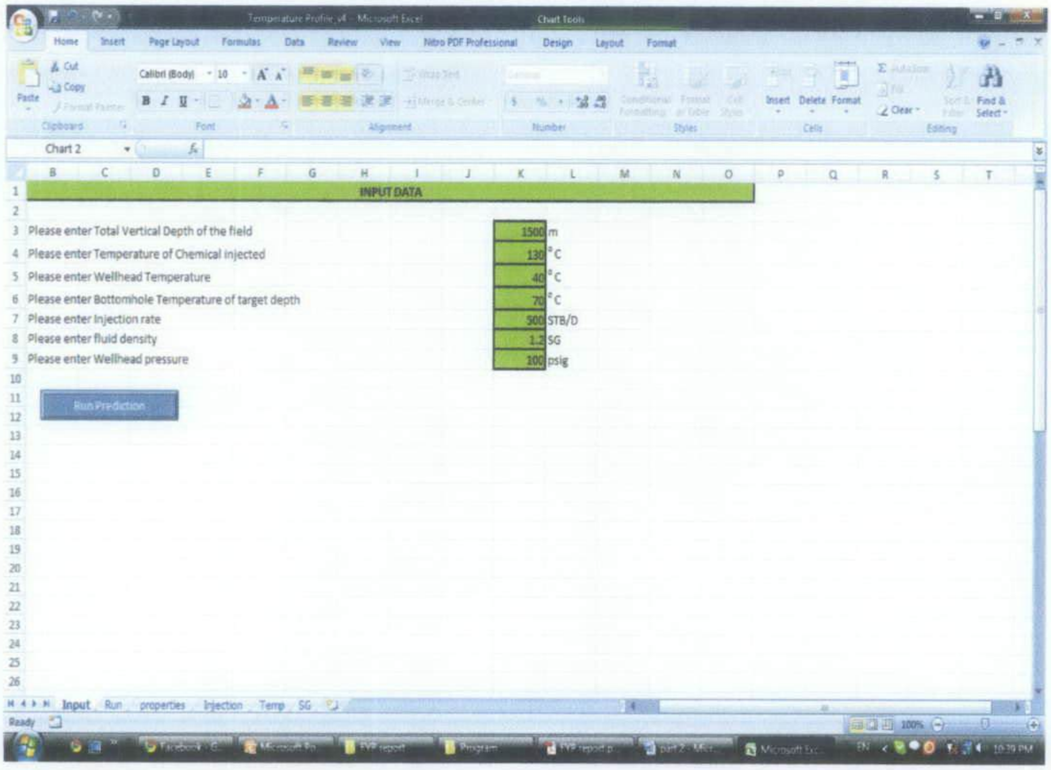


Figure 4: Input in Microsoft Excel® 2007.

2. After all necessary data are entered into the template, "Run Prediction" button below is clicked to start the simulation.

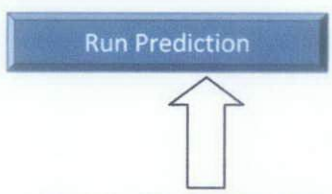


Figure 5: "Run Prediction" button

3. Once "Run Prediction" button is clicked, prediction of temperature profile will be started. Prediction of temperature profile is done in another tab called "Run".

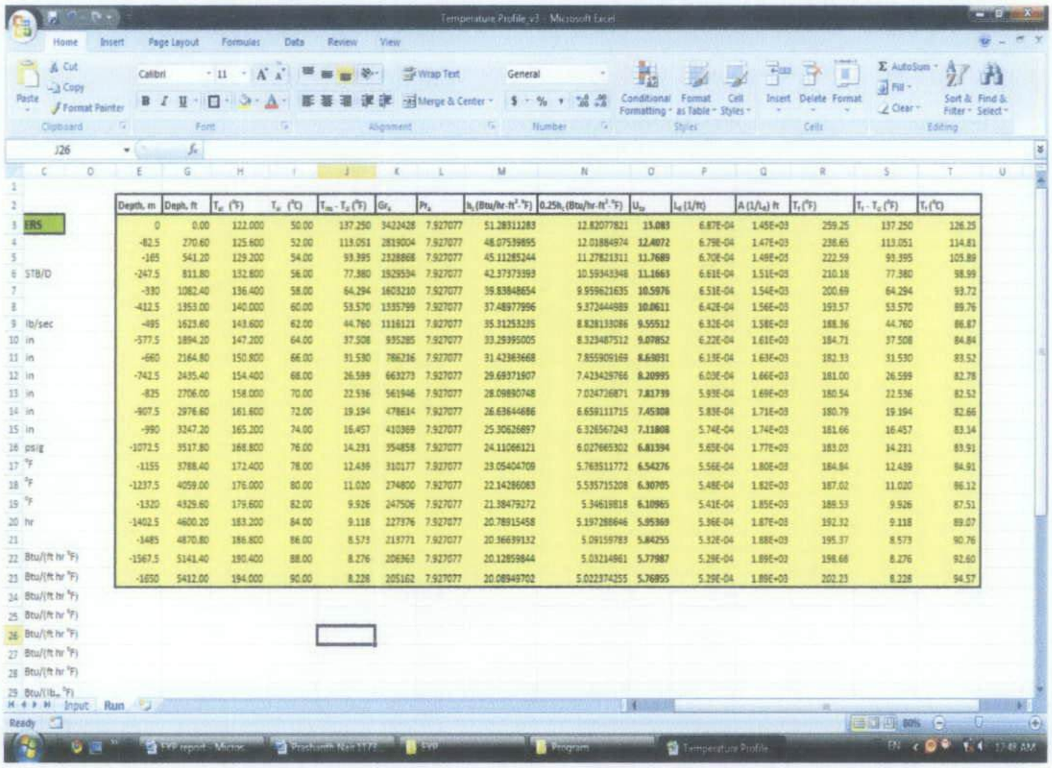


Figure 6: Prediction of temperature profile in Microsoft Excel® 2007.

4. After prediction of temperature profile is done in "Run" tab, formation temperature and chemical temperature will be plotted in the chart located in "Input" tab.

4.6 Gantt Chart

Final Year Project 1

No.	Detail / Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1.	Selection of Project Topic															
2.	Preliminary Research Work															
3.	Literature Review & Information Gathering															
4.	Submission of Preliminary Report															
5.	Learning Computer Programming															
6.	Collection of Field Data															
7.	Submission of Progress Report															
8.	Submission of Interim Report Final Draft															
9.	Oral Presentation															

Table 1: Gantt Chart of Final Year Project 1

Dateline

Process

Final Year Project 2

No.	Detail / Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1.	Prediction of Temperature Drop																
2.	Prediction of Chemical Needed																
3.	Submission of Progress Report																
4.	Collection of Field Data																
5.	Testing of Computer Program																
6.	Pre EDX																
7.	EDX																
8.	Final Oral Presentation																
9.	Delivery of Hardbound Report to External Examiner																
10.	Submission of Hardbound Copies																

Table 2: Gantt Chart of Final Year Project 2

Dateline

Process

CHAPTER 5

RESULTS AND DISCUSSIONS

5.1 Assumptions

Throughout the prediction of temperature profile of injected chemical, there are several assumptions that are needed to be considered before running the tool.

1. The well is a vertical well.
2. Injected chemical is single phase only.
3. Chemical properties are remained constantly throughout prediction.

5.2 Results

A reference input is created based on field data from Hasan and Kabir (2002). In the textbook, field data is used to show the procedure for calculating chemical temperature in injection well. Data below are basic properties for well.

d_{ti}	= 3.00 in	K_c	= 25.907257 Btu/(ft hr oF)
d_{to}	= 4.00 in	K_e	= 1.508319 Btu/(ft hr oF)
d_{ins}	= 5.00 in	K_{cem}	= 4.019747526Btu/(ft hr oF)
d_{ci}	= 6.50 in	K_a	= 0.335182 Btu/(ft hr oF)
d_{co}	= 7.00 in	K_f	= 0.335182 Btu/(ft hr oF)
d_{wb}	= 9.00 in	K_{ins}	= 25.90726 Btu/(ft hr oF)
P_{wh}	= 100 psig	K_{tub}	= 25.907257 Btu/(ft hr oF)
T_{wh}	= 40 °C	$C_{p,w}$	= 0.998393 Btu/(Ibm oF)
T_{bh}	= 70 °C		
Depth	= 1500 ft		

Data of chemical injected is shown below.

T_{inj} = 130 °C
Q_{inj} = 500 STB/D
γ_{inj} = 1.01

Results of the prediction are shown below in graph.

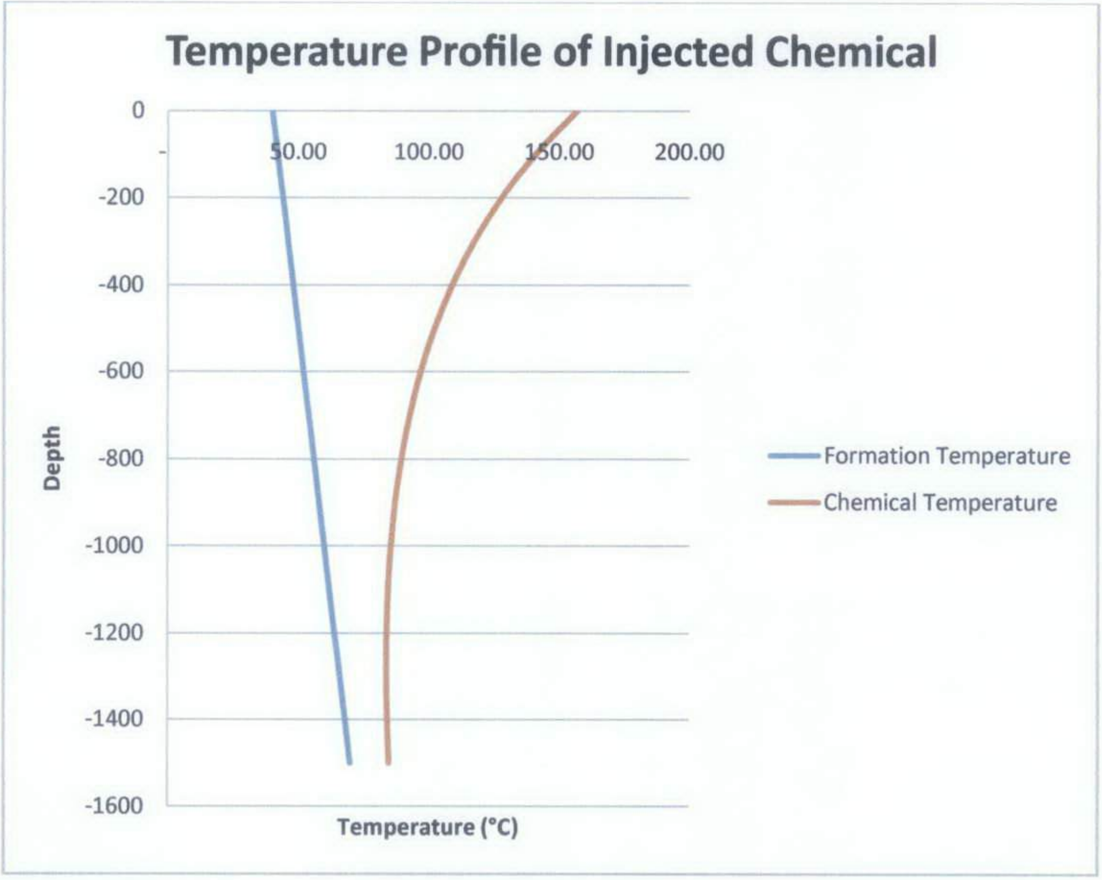


Figure 7: Temperature Profile of Injected Chemical.

5.3 Sensitivity Analysis

By using results on last section, effects of sensitivity parameters were studied. These studies are important as it will give insight on design of injected chemical. Some of the sensitivity parameters selected are injection rate, injection temperature and fluid density.

5.3.1 Effects of Injection Rate

Injection rate is selected as one of sensitivity parameters that can affect temperature of chemical injected. Range of injection rate is from 100 STB/D to 1000 STB/D.

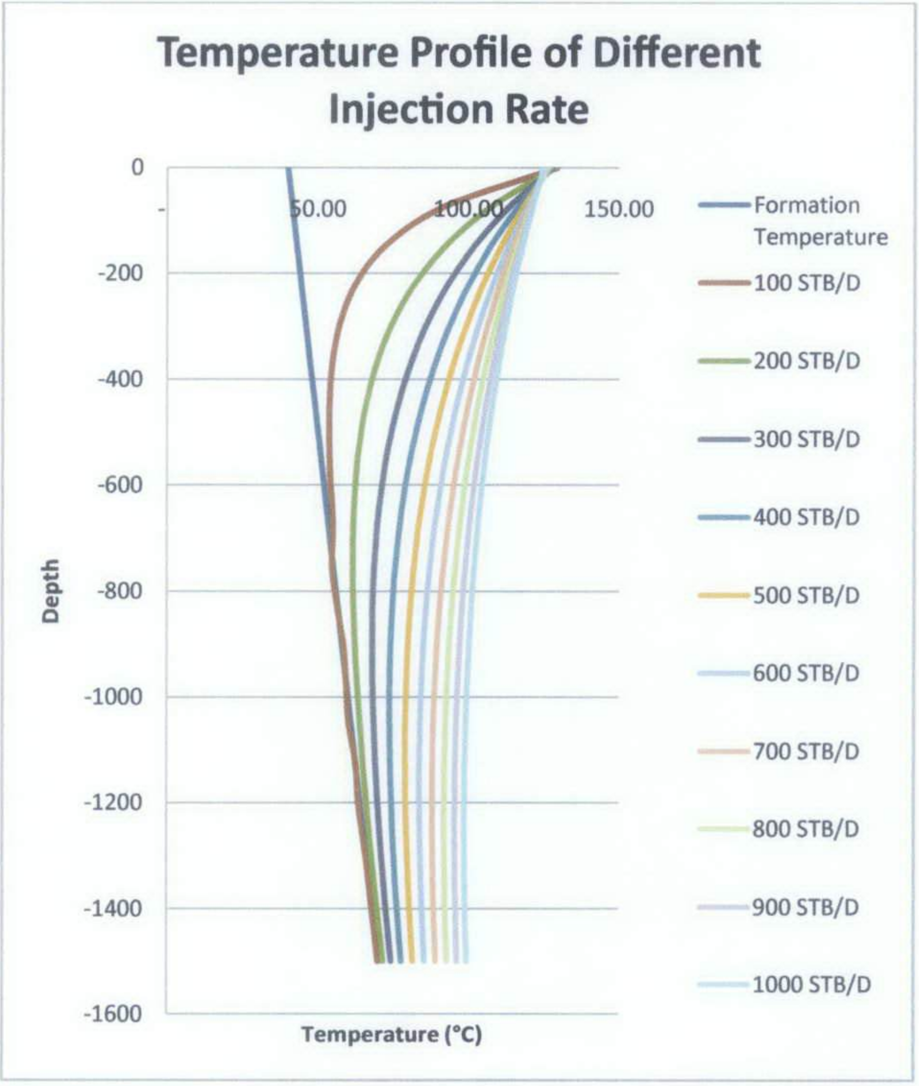


Figure 8: Temperature Profile of Different Injection Rate

From the graph above, higher injection rate has higher fluid temperature when it reaches bottomhole. So, higher injection rate is better for organic solid deposition treatment.

5.3.2 Effects of Injection Temperature

For second sensitivity analysis, injection temperature is selected. Injected temperature is varied between 120°C to 160°C.

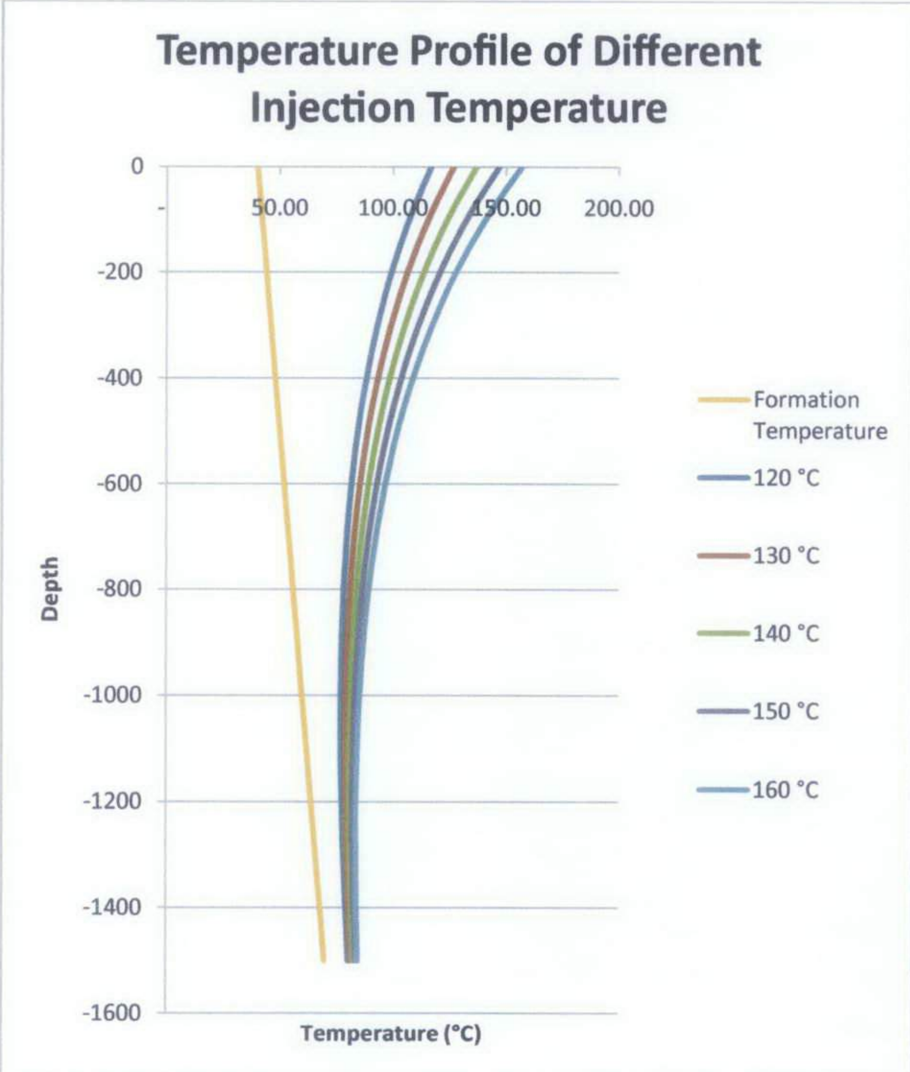


Figure 9: Temperature Profile of Different Injection Temperature

From the graph above, higher temperature of fluid injected will have higher fluid temperature at bottomhole. But temperature difference between different fluid temperature injected is less.

5.3.3 Effects of Fluid Density

Fluid density is varied from 0.7 Specific Gravity (SG) to 1.2 SG to examine effects of fluid density to bottomhole temperature.

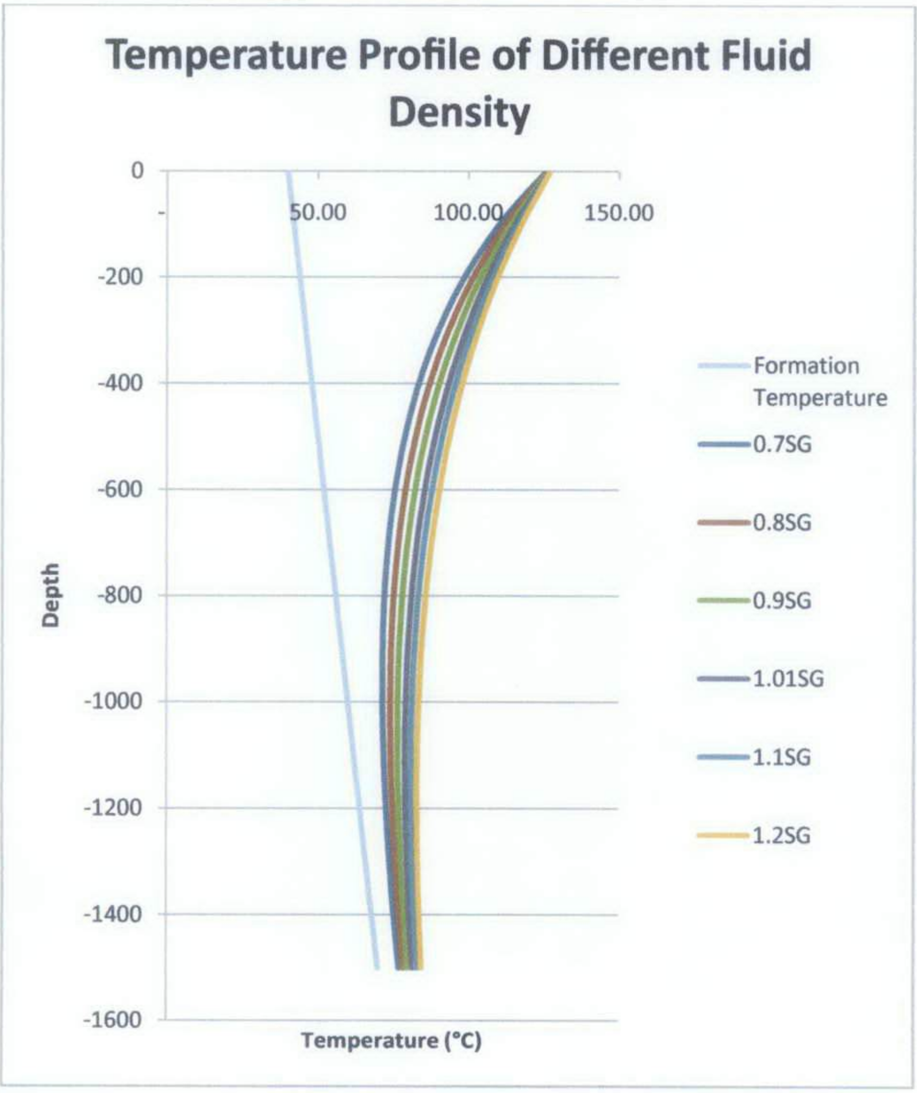


Figure 10: Temperature Profile of Different Fluid Density

From graph above, given same fluid temperature at injection point, when fluid density is higher, temperature of fluid injected at bottomhole is higher too.

5.4 Discussions

Based on results obtained through simulation created, effects of three sensitivity parameters are studied in details.

5.4.1 Effects of Injection Rate

From Figure 8, when injection rate is higher, temperature of injected fluid will be higher when it reaches bottomhole, with same fluid temperature at point of injection. When there is high injection rate, travelling time for fluid will take less time to reach bottomhole. So, contact time of fluid with surroundings will be less. As contact time between fluid and surroundings is less, heat transfer between fluid and surroundings of higher injection rate is less compared to lower injection rate. Thus, fluid temperature at bottomhole is higher with higher injection rate.

5.4.2 Effects of Injection Temperature

From Figure 9, although higher injection temperature has higher fluid temperature at bottomhole, temperature at bottomhole has no much difference for all injection temperature. Temperature difference at bottomhole is around 1°C difference for every 10°C increment at the point of injection. Higher injection temperature has more temperature drop as there is higher temperature difference between fluid and surrounding. So, heat transfer between fluid in the wellbore and formation is higher. So, temperature drop of higher injection temperature is higher. This results in little difference in chemical temperature when it reaches bottomhole.

5.4.3 Effects of Fluid Density

From Figure 10, with same fluid temperature at the point of injection, when fluid density is higher, temperature of fluid injected at bottomhole is higher. Reason behind this phenomenon is that with higher fluid density, molecules inside fluid carry more energy. When heat from fluid is dissipated to surroundings, high density fluid will retain more amount of heat although all fluid has same initial temperature. Temperature drop of high density fluid is lower compared to low density fluid. Thus, fluid temperature of high density fluid is higher when it reaches bottomhole.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

In the nutshell, objectives of this project are met. Objectives of this project are:

a) To investigate heat loss and temperature drop of injected chemical into the tubular.

b) To investigate various parameters that will affect injected chemical temperature at bottomhole.

c) To evaluate the computer program created.

Program created has shown that the result is plausible. Prediction in the program created shows that temperature of injected chemical decreases as temperature of fluid injected is higher than formation temperature. Chemical temperature continues to drop until there is a point where there is little difference between formation temperature and chemical temperature at that point. After that point, chemical temperature continues to rise as formation temperature is rising. This program created can be applied to other type of fluid like steam and water.

6.2 Recommendations

Three sensitivity parameters that will affect heat transfer of chemical to surroundings are identified. These sensitivity parameters are injection rate, injection temperature and fluid density. When injection rate is higher, chemical temperature at bottomhole is higher. Injection temperature does not make a lot of difference as high temperature difference between chemical and formation will accelerate heat transfer. Higher fluid density will result in higher chemical temperature at bottomhole. Thus, optimal chemical condition for organic solid deposition treatment will be high injection rate, high chemical density and suitable injection temperature.

6.3 Future Works

This project is still in testing phase as it only examines temperature profile of injected chemical. Future works that can be done to improve this project are:

a) Inclusion of inclination angle
b) Inclusion of two phase flow, which include steam injection
c) Examination of effects of injection pressure

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